DEVELOPMENT OF MODELING INVENTORY AND BUDGETS FOR THE OZONE TRANSPORT SIP CALL

U.S. Environmental Protection Agency
Office of Air and Radiation
March 23, 1998

Table of Contents

CHAPTER I
INTRODUCTION

The purpose of this document is to describe the development of the point source emissions and control data used in the United States (U.S.) Environmental Protection Agency's (EPA) modeling associated with the Ozone Transport State Implementation Plan (SIP) Call and to describe the process for calculation of the associated Statewide budgets. The point source data used in EPA's modeling of the Ozone Transport SIP Call have changed from the point source data used in the Ozone Transport Assessment Group's (OTAG) modeling. This document describes the development of these new point source data and their differences from the point source data used in the OTAG modeling. This document also describes differences between these data and the data used to calculate the budgets for the November 7, 1997 Notice of Proposed Rulemaking (NPR).

The point source data for the modeling effort were divided into two components: electricity generating unit (EGU) data and non-electricity generating unit (non-EGU) data. The point source data were divided in this way for four reasons:

1. Different data sources were used for the development of the base year emissions data.

2. Different growth factors were used to project future emissions.

3. Different levels of controls were applied to EGU and non-EGU sources.

4. EGU and non-EGU emissions make up separate components of the NO_x budget developed as part of the Ozone Transport SIP Call.

The development of the EGU and non-EGU emissions and control data are described separately in this document.

The point source data used for the Ozone Transport SIP Call modeling and budget differ from the point source data used by OTAG in the following ways:

- The base year has been changed from 1990 (OTAG base year) to 1995 for the Ozone Transport SIP call for all sources except EGUs for which the base year is 1995 or 1996., depending on each State's EGU fuel usage.

- A new base year inventory was developed for EGUs and many OTAG electric utility data have been updated through the use of data from continuous emissions monitoring systems as reported to EPA under 40 CFR Part 75.

- Different growth factors based on EPA's Integrated Planning Model (IPM) are used for projecting EGU emissions.

- Sources that were inappropriately categorized as EGUs in the OTAG modeling have been added to the non-EGU sector and removed from the EGU sector.

Chapter II of this document describes the development of the EGU data and Chapter III describes the development of the non-EGU point source data. Development of area and mobile source data is not included in this document because they are unchanged from the OTAG Run 5 modeling and are unchanged from the NPR. The development of the emissions and control data associated with OTAG Run 5 modeling was documented as part of the OTAG process (Pechan, 1997a, Pechan, 1997b). The area and mobile source sectors are included in the discussion of Statewide Budgets in Chapter IV.

CHAPTER II
EGU DATA

A. DEVELOPMENT OF BASE YEAR DATA

The base year EGU data base developed for this modeling effort consists of both electric utility units and nonutility electricity generating units. The nonutility electricity generating units include independent power producers (IPPs) and nonutility generators (NUGs). Two alternative base year data sets were developed: one using the higher of 1995 or 1996 heat input (determined at the State-level) and one using 1996 heat input. For each base year data set both seasonal (for budget determination) and daily emission estimates (for modeling) were developed.

Eight data sources were used to develop the base year EGU data:

1. EPA's Acid Rain Data Base (ARDB) (Pechan, 1997c);
2. EPA's 2007 Integrated Planning Model Year 2007 (IPM);
3. EPA's Emission Tracking System/Continuous Emissions Monitoring System (ETS/CEM) (EPA, 1997b);
4. DOE's Form EIA-860 (DOE, 1995a);
5. DOE's Form EIA-767 (DOE, 1995b);
6. EPA's National Emissions Trends Data Base (NET) (EPA, 1997c);
7. DOE's Form EIA-867 (DOE, 1995c); and
8. The OTAG Emission Inventory (Pechan, 1997a).

Each of these data sources is described below.

EPA's Acid Rain Data Base (ARDB) was developed in response to the Acid Rain Program authorized under Title IV. The data base was originally an update to the boiler-based National Allowance Data Base Version 3.11 (NADBV311) which was used in the calculation of the SO_2 allowances as specified in Title IV. Over the last few years, the data base has been expanded to include ETS/CEM 1994-1996 SO_2, NO_x, CO_2, and heat input; as well as 1985-1995 NET utility data, boiler identification, characteristics, and locational data. The existing boilers and planned turbines (as of 1990) in the ARDB are used as units for the EGU.

EPA's 2007 Integrated Planning Model Year 2007 (IPM) data base represents a unit-level disaggregated IPM Clean Air Act (CAA) baseline simulation developed for OTAG modeling. The IPM includes over 7,000 records (nationally) with data on existing electricity generating units. The records are maintained in EPA's National Electric Energy Data System (NEEDS). In general, generator-level utility turbines and engines, as well as nonutility units that are not required to report to EPA under the Title IV program, are used as units for the EGU. Supplemental data, provided by EPA, including the start year, the base year (1994) NO_x rate, and type of ownership, were added to the IPM data base. This file was used to obtain NO_x emissions and heat input data for these units. Where units could be matched to other inventories, actual locational data are included in the IPM; otherwise, county centroids are used.

EPA's Emission Tracking System/Continuous Emissions Monitoring System (ETS/CEM) data contains hourly SO_2, CO_2, NO_x rate, and heat input data at the monitoring stack level and boiler level for all boilers included in the Acid Rain Program that was mandated by Title IV of the Clean Air Act Amendments of 1990 (CAAA). In 1994, data were collected from the 263 Phase I boilers; beginning in 1995, data are collected from Phase II as well as Phase I affected boilers. These data were used for NO_x tons and heat input. Data were provided in a variety of files from EPA.

DOE's Form EIA-860 is an annual utility survey, "Annual Electric Generator Report," that provides utility data on a generator level. Both existing and planned generators are reported; the data include generator identification data, status, capacity, prime mover, and fuel type(s). Units reported on this form were generally only included in the EGU file if they also were included in the IPM file since NO_x tons and heat input are not derivable from Form EIA-860 alone. This form was useful, however, in providing other information, such as prime mover and unit status.

DOE's Form EIA-767 is an annual survey, "Steam-Electric Plant Operation and Design Report," that contains data for fossil fuel steam boilers such as fuel quantity and quality; boiler identification, locational, status, and design information; and FGD scrubber and particulate collector device information. Note that boilers in plants with less than 10 MW do not report all data elements. The relationship between boilers and generators is also provided, along with generator-level generation and nameplate capacity. Note that boilers and generators are not necessarily in a one-to-one correspondence.

EPA's NET fossil fuel steam data base has been developed for EPA for many years. The data base is initially based on DOE's Form EIA-767 data, but the coal NO_x emissions have been superseded by calculations using EPA NO_x rates, and the NO_x, SO_2 and heat input data from ETS/CEM are always used if available. Source Classification Codes (SCCs) are assigned to each boiler based on boiler and fuel characteristics; AP-42 emission factors are always used to calculate VOC, CO, PM10, and PM2.5 emissions. The 1990 and 1995 Trends data bases were used to obtain SCCs, stack parameters, and NO_x tons and heat input.

DOE's Form EIA-867 ("Annual Nonutility Power Producer Report") is similar in content to, although more limited than, the utility Forms EIA-860 and EIA-767. The EIA-867, however, is a confidential form, and aside from the facility identification data (which includes State and capacity), EIA can only provide most data from this form on an aggregated basis. Only a few of the records from this file were ultimately used since it was difficult to obtain NO_x tons, heat input, or locational data unless they matched to another source.

The OTAG data base was developed by collecting and compiling electric utility emission inventory data from States in the OTAG domain. This inventory is for the year 1990 and contains summer day emission estimates, as well as variables required for photochemical modeling. This data base was used to obtain NO_x and locational data.

In general, the operating units in the ARDB identified the steam boilers, while the IPM data base identified the generator-level utility turbines and engines, as well as the nonutility units. While some units originated in the other data bases, their primary purpose was to add variables required for modeling to the units identified by the ARDB or IPM data.

In order for a unit to be used, it had to have enough data to estimate emissions. Data had to be available on either daily or seasonal heat input or daily or seasonal NO_x emissions. The NO_x emission rate was also required, but a default NO_x emission rate from AP-42 was assigned to units that had data on heat input or emissions, and no NO_x rate. The emissions from 421 units could not be estimated because there was no NO_x emissions or heat input information available to EPA for these units. This suggests that these units may not have operated in the summer seasons of 1995 and 1996.

The first step in developing the base year data was to develop a file containing all available heat input, NO_x emissions and NO_x rate information.

1. Seasonal NO_x Tons and Heat Input

The hierarchy for obtaining seasonal NO_x tons and heat input for a particular unit is provided below.

For the 1995/1996 Base Year:

1. Determine what year of data to use for a given boiler, based on the State that the boiler is in and whether 1996 or 1995 heat input was higher for that State.

2. Based on that boiler year information, use ETS/CEM data to obtain 1996 seasonal NO_x tons and 1996 seasonal heat input, or 1995 seasonal NO_x rate and 1995 seasonal heat input to calculate 1995 seasonal NO_x tons.

3. Based on that boiler year information, use the 1996 projected or 1995 NET data base (Both of which include annual boiler-level ETS/CEM data) for annual NO_x tons and heat input, then convert to seasonal.

4. Use 1990 OTAG file for ozone season day (OSD) NO_x tons and OSD heat input (or July month heat input and divide by 31), then convert to seasonal and forecast.

5. Use IPM 1994 NO_x rate and 2007 July heat input, calculate NO_x tons, convert to seasonal, and backcast.

6. If there is a heat input and no NO_x tons or rate, assign an AP-42 default NO_x rate based on SCC and convert to seasonal.

For 1996 Base Year:

1. Use ETS/CEM 1996 file for seasonal NO_x tons and 1996 seasonal heat input.

2. Use the 1996 projected or 1995 NET data base (both of which include annual boiler-level ETS/CEM data) for annual NO_x tons and heat input, then convert to seasonal.

3. Use 1990 OTAG file for OSD NO_x tons and OSD heat input (or July month heat input and divide by 31), then convert to seasonal and forecast.

4. Use IPM1994 NO_x rate and 2007 July heat input, calculate NO_x tons, convert to seasonal, and backcast.

5. If there is a heat input and no NO_x tons or rate, assign an AP-42 default NO_x rate based on SCC and convert to seasonal.

2. Source Classification Codes (SCCs)

The methodology for assigning SCC is as follows:

1. Match with NET 1995 or 1990 inventory and assign the major SCC (based on heat input) to the boiler.

2. Match with OTAG and assign the major SCC.

3. Assign default SCCs based on prime mover, fuel type, and (in the case of steam units) boiler bottom and firing types.

3. Stack Parameters

The methodology for obtaining stack parameters is as follows:

1. Match with NET 1995 or 1990 inventory and use the stack data.

2. Match with OTAG and use the stack data.

3. Assign default stack parameters, based on prime mover and fuel type, that were originally developed for the Regional Oxidant Model (ROM). (Note that since stack parameters in IPM were originally developed by matching with OTAG and NET inventories, followed by defaults, any stack parameters obtained from IPM are likely to be default parameters.)

Appendix A is a list of the daily data for the entire base year EGU Inventory for the 23 jurisdictions covered by the Ozone Transport SIP Call. Appendix B is a list of the seasonal data for the entire base year EGU Inventory.

B. 2007 BASE CASE

The 2007 Base Case was developed by applying growth factors to the 1996 Base Year and then applying applicable controls required by the CAAA. Applicable controls required for EGUs included Title IV Acid Rain controls and NO_x RACT controls.

1. Growth Factors

The growth factors used in the 2007 Base Case were supplied by EPA and came from their IPM projections. The growth factors are at the State-level (i.e., there was a single growth factor for each State that was applied to all units in that State). Since publication of the NPR, EPA has corrected its estimates of State-specific growth rates from 1996 to 2007. The estimates were interpolated from the average annual growth of each State as forecasted by EPA using the IPM and EPA's baseline electric generation forecast. In developing the average annual growth, EPA relied on unit-specific summer energy use from 2000 to 2010 as forecasted by the IPM. The average annual growth was determined by dividing the State-specific growth from 2000 to 2010, by 10. However, when calculating the growth for the year 2010, EPA inadvertently omitted information on many of the new combustion turbine and combined-cycle units that IPM forecasts to be built by 2010. Thus new electricity-generating capacity, expected to be built between 2000 and 2010 was not included when estimating the industry growth between 2000 and 2010. This error resulted in an underestimation of the expected average annual growth for each affected State. In the modeling and in the revision of the budget for the electric power industry, this error has been corrected. The change leads to a higher EGU NO_x budget component for all affected States. The revised growth factors are shown in Table II-1.

The growth factors were applied to the 1996 heat input to get 2007 projected heat input. Emissions were then estimated by multiplying the 2007 projected heat input by the 2007 Base Case projected NO_x rate. The

2007 Base Case projected NO_x rate was estimated based on applicable controls applied to each unit as described below.

2. Control Factors

The Base Case NO_x emission rate was assumed to be the same as the 1996 Year NO_x emission rate unless the unit was subject to controls required by the CAAA. EPA supplied 2007 Base Case NO_x emission rates that accounted for Title IV Acid Rain controls.

C. 2007 BUDGET CASE

1. Application of SIP Call controls

The 2007 Budget Case was exactly the same as the 2007 Base Case except that units with a size of 25 MW or greater in the 23 State area had an emission rate of 0.15 lb NO_x/MMBtu substituted for their 2007 Base Case NO_x emission rate.

D. EGU EMISSION SUMMARY

Table II-2 is a State-level summary of the EGU data. It contains both daily and seasonal heat input and emissions for the 1995/1996 base year, the 1996 base year, the 2007 Base Case, and the 2007 Budget Case. Table II-3 is a comparison of the State-level seasonal emissions calcualted using the assumptions described above to the Base Case and Budget components that were calculated for the November 7, 1997 NPR.

Table II-1
IPM Growth Factors

State	Old 96-07 Factor	New 96-07 Factor	Percent Increase
Alabama	1.03	1.16	12.9%
Connecticut	0.92	1.22	33.0%
District of Columbia	1.00	1.00	0.0%
Delaware	1.68	1.80	6.8%
Georgia	1.14	1.21	6.3%
Illinois	1.23	1.34	8.6%
Indiana	1.27	1.30	2.6%
Kentucky	1.20	1.28	6.4%
Massachusetts	1.62	1.71	5.6%
Maryland	1.14	1.23	7.4%
Michigan	1.13	1.18	4.6%
Missouri	1.13	1.24	9.3%
North Carolina	1.10	1.26	15.0%
New Jersey	0.99	1.26	27.4%
New York	1.11	1.22	10.2%
Ohio	1.10	1.14	3.2%
Pennsylvania	1.07	1.15	7.1%
Rhode Island	0.43	0.48	11.8%
South Carolina	1.32	1.63	23.2%
Tennessee	0.92	1.25	35.8%
Virginia	1.18	1.43	20.5%
Wisconsin	1.07	1.13	6.3%
West Virginia	1.02	1.05	3.3%

Table II-2
State Level Summary of EGU Data

	1995/1996				1996				2007 Base				2007 Budget	
	Heat Input		Emissions		Heat Input		Emissions		Heat Input		Emissions		Heat Input	
State	Daily (MMBTU/day)	Seasonal (MMBTU/season)	Daily (tons/day)	Seasonal (tons/season)	Daily (MMBTU/day)	Seasonal (MMBTU/season)	Daily (tons/day)	Seasonal (tons/season)	Daily (MMBTU/day)	Seasonal (MMBTU/season)	Daily (tons/day)	Seasonal (tons/season)	Daily (tons/day)	Seasonal (tons/season)
AL	2,503,648	352,425,386	699	99,156	2,503,648	352,425,386	699	99,156	2,904,232	408,813,448	601	85,201	218	30,644
CT	501,040	57,277,690	52	6,046	501,040	57,277,690	52	6,046	611,269	69,878,781	61	7,048	46	5,245
DC	31,698	2,026,073	4	246	2,006	128,205	0	23	31,698	2,026,073	4	236	2	152
DE	291,168	36,929,685	57	7,341	291,168	36,929,685	57	7,341	524,103	66,473,433	83	10,727	39	4,994
GA	2,623,259	356,142,667	616	84,977	2,447,655	336,016,009	585	80,736	3,174,143	430,932,627	616	84,890	239	32,433
IL	2,629,757	356,594,313	837	113,741	2,629,757	356,594,313	837	113,741	3,523,875	477,836,380	881	119,756	270	36,570
IN	3,663,468	518,143,729	1,104	156,317	3,663,468	518,143,729	1,104	156,317	4,762,508	673,586,848	1,130	159,917	366	51,818
KY	2,840,117	399,870,754	1,074	151,372	2,820,797	397,253,486	1,066	150,248	3,635,350	511,834,565	929	130,919	275	38,775
MA	849,026	113,610,194	108	14,755	849,026	113,610,194	108	14,755	1,451,835	194,273,431	183	24,998	109	14,651
MD	1,090,463	140,695,289	326	43,849	996,499	128,789,315	333	44,807	1,341,269	173,055,205	280	37,575	100	12,971
MI	2,152,633	321,351,989	539	79,887	2,152,633	321,351,989	539	79,887	2,540,107	379,195,347	496	73,585	197	29,458
MO	2,000,489	278,166,762	570	79,567	2,000,489	278,166,762	570	79,567	2,480,606	344,926,785	587	81,799	190	26,450
NC	2,575,406	343,950,596	941	125,237	2,575,406	343,950,596	941	125,237	3,245,011	433,377,751	652	86,872	245	32,691
NJ	847,111	85,651,705	139	16,235	825,719	82,699,031	123	14,580	1,067,360	107,921,149	149	17,484	81	8,191
NY	3,106,076	367,258,886	364	45,624	2,710,204	320,869,354	303	38,328	3,789,413	448,055,841	346	43,705	259	31,222
OH	4,165,199	580,183,164	1,651	230,437	4,165,199	580,183,164	1,651	230,437	4,748,327	661,408,807	1,201	167,601	370	51,493
PA	3,970,333	526,794,838	852	116,640	3,970,333	526,794,838	852	116,640	4,565,883	605,814,064	880	120,979	346	45,971
RI	327,954	44,807,166	23	2,813	327,954	44,807,166	23	2,813	157,418	21,507,440	11	1,351	12	1,609
SC	1,205,929	162,324,649	417	56,172	1,205,929	162,324,649	417	56,172	1,965,664	264,589,177	424	57,146	147	19,842
TN	1,976,188	279,734,359	929	131,469	1,899,491	268,877,789	801	113,329	2,470,235	349,667,949	592	83,844	185	26,225
VA	1,591,900	195,191,912	419	53,707	1,402,531	171,531,553	365	46,591	2,276,418	279,124,435	403	51,113	171	20,990
WI	1,405,681	201,888,002	302	43,555	1,352,208	194,167,020	296	42,620	1,588,419	228,133,443	316	45,538	121	17,345
WV	2,216,129	305,333,381	847	116,758	2,216,129	305,333,381	847	116,758	2,326,936	320,600,051	554	76,374	175	24,045
Total	44,564,672	6,026,353,189	12,871	1,775,901	43,509,289	5,898,225,305	12,568	1,736,127	55,182,077	7,453,033,028	11,381	1,568,655	4,165	563,784

Table II-3
Changes to Proposed Base Case and Budget Components for Electricity Generating Units (tons NO_x/season)

State	Proposed Base	Revised Base	Percent Increase	Proposed Budget	Revised Budget	Percent Increase
Alabama	81,704	85,201	4%	26,946	30,644	14%
Connecticut	5,715	7,048	23%	3,409	5,245	54%
Delaware	10,901	10,727	-2%	4,390	4,994	14%
District of Columbia	385	236	-39%	152	152	0%
Georgia	92,946	84,890	-9%	30,158	32,433	8%
Illinois	115,053	119,756	4%	31,833	36,570	15%
Indiana	177,888	159,917	-10%	48,791	51,818	6%
Kentucky	128,688	130,919	2%	35,820	38,775	8%
Maryland	35,332	37,575	6%	11,364	12,971	14%
Massachusetts	28,284	24,998	-12%	12,956	14,651	13%
Michigan	82,057	73,585	-10%	25,402	29,458	16%
Missouri	92,313	81,799	-11%	22,932	26,450	15%
New Jersey	14,553	17,484	20%	5,041	8,191	62%
New York	39,639	43,705	10%	24,653	31,222	27%
North Carolina	83,273	86,872	4%	27,543	32,691	19%
Ohio	185,757	167,601	-10%	46,758	51,493	10%
Pennsylvania	125,195	120,979	-3%	39,594	45,971	16%
Rhode Island	773	1,351	75%	905	1,609	78%
South Carolina	43,363	57,146	32%	15,090	19,842	31%
Tennessee	71,994	83,844	16%	19,318	26,225	36%
Virginia	45,719	51,113	12%	16,884	20,990	24%
West Virginia	83,719	76,374	-9%	23,306	24,045	3%
Wisconsin	51,004	45,538	-11%	15,755	17,345	10%
Total	1,596,255	1,568,655	-2%	489,000	563,784	15%

CHAPTER III
NON-EGU DATA

The non-EGU data include all point sources that do not generate electricity. The base year for non-EGU sources is 1995. The primary data source for the non-EGU data was the 1990 OTAG Inventory (Pechan, 1997a). With the exception of projecting the 1990 OTAG emissions to 1995, few changes were made to the non-EGU data.

A. DEVELOPMENT OF 1995 BASE YEAR EMISSIONS

The starting point for the non-EGU base year 1995 emissions was the 1990 OTAG Inventory. All records with utility SCCs (first 3 digits 101 or 201) were removed from the 1990 OTAG Inventory because it was assumed that emissions from these sources would be accounted for in the EGU component of the inventory.

1,162 records from the 1990 OTAG Inventory with SCCs starting with 101 or 201 were added back into the non-EGU component of the inventory because corresponding data for these records could not be found in the EGU component of the inventory, and therefore it was assumed that their SCCs had been assigned incorrectly. These 1,162 records accounted for 189 tons per day of NO_x in 1990. The SCCs for these units were changed to nonutility SCCs by changing the first 3 digits of the SCC from 101 to 102 or from 201 to 202. For a small number of records this change resulted in invalid SCCs. In those cases the SCCs were modified to a valid SCC with similar characteristics (i.e., fuel and boiler type) as the original utility SCC. Appendix C contains the complete list of records moved from the OTAG utility data to the SIP Call non-EGU data.

The next step in developing the 1995 non-EGU emission estimates was to project the 1990 data from OTAG to 1995. The inventory data for 1990 were projected to 1995 using Bureau of Economic Analysis (BEA) historical estimates of industrial earnings at the 2-digit Standard Industrial Classification (SIC) level. Growth factors developed based on the change in earnings between 1990 and 1995 were applied to 1990 NO_x emissions, as well as 1990 VOC and CO emissions. This is the same process and data that was used to develop the emissions for the OTAG 1995 episode.

NO_x RACT controls were applied to major sources in ozone nonattainment areas (NAA) and the Ozone Transport Region (OTR) unless the area received a NO_x waiver. The data to model NO_x RACT came from the OTAG data base which was developed by surveying applicable States on their implementation of NO_x RACT (Pechan, 1997b). These data include unit specific NO_x RACT control efficiencies for 1,177 units. For units without specific control information either NAA/SCC NO_x RACT efficiencies collected from the States or national/SCC NO_x RACT default efficiencies were applied. This is the same process and data that was used to apply NO_x RACT for the OTAG 1995 episode.

B. 2007 BASE CASE

The inventory data for 1995 was projected to 2007 using BEA projections of Gross State Product (GSP) at the 2-digit SIC) level BEA at the 2-digit SIC level. To be consistent with the OTAG 2007 projections, the growth factors developed were based on the change in projected GSP between 1990 and 2007. Then amount of growth estimated to have occurred between 1990 and 1995 was factored out of the 1990 to 2007 growth factors using the following formula:

$$GF_{1995\ to\ 2007} = \frac{GF_{1990\ to\ 2007}}{GF_{1990\ to\ 1995}}$$

where:

$GF_{1995to2007}$ = the 1995 to 2007 growth factor used to project from 1995 to 2007
$GF_{1990to2007}$ = the 1990 to 2007 growth factor used in OTAG to project from 1990 to 2007
$GF_{1990to1995}$ = the 1990 to 1995 growth factor used to project the 1990 OTAG emissions to 1995 for the SIP Call base year data.

The resulting 1995 to 2007 growth factors were applied to the 1995 base year emissions to project 2007 emissions. Using these growth factors resulted in growth consistent with that used in the OTAG projections.

No NO_x controls in addition to NO_x RACT were applied in the Base Case. The same VOC controls that were applied to the OTAG Base Case were applied to this Base Case. No CO controls were applied.

C. 2007 BUDGET CASE

For the 2007 Budget Case a distinction was made between large (>250 MMBtu/hr), medium (<250 MMBtu/hr and emitting more than 1 ton/day) and small (<250 MMBtu/hr and emitting less than 1 ton/day) points for the non-EGU sources. A majority of the non-EGU point source records in the OTAG Inventory did not include the boiler capacity. Data from EPA’s NET Inventory were used to determine whether a non-EGU source was modeled to be a large, medium, or small source exactly as was done for OTAG Round 3 modeling.

Using data from the NET data base a default boiler capacity file that contained the mean and median boiler capacities by 6-digit SCC was developed. For each 6-digit SCC the file also contained the average daily NO_x emissions for records with boiler capacities closest to 250 MMBtu/hr. These data are listed in Table III-1. For example, for a given 6-digit SCC the boiler capacity closest to 250 MMBtu/hr may have been 270 MMBtu/hr. If there was only one record with a boiler capacity of 270 MMBtu/hr, we included the daily NO_x emissions from that record. If more than one record had a boiler capacity of 270 MMBtu/hr the mean daily emissions of those records was used.

Each non-EGU record in the inventory was matched to the file described above based on its 6-digit SCC. The following four rules were used for determining if a unit’s boiler capacity was greater than or less than 250 MMBtu/hr.

1. If both the mean and median boiler capacity in the file were greater than 300 MMBtu/hr, it was assumed that the record’s boiler capacity was greater than 250 MMBtu/hr.

2. If both the mean and median boiler capacity in the file were less than 200 MMBtu/hr, it was assumed that the record’s boiler capacity was less than 250 MMBtu/hr.

3. If either the mean or median boiler capacity was in between 200 and 300 MMBtu/hr, then the daily NO_x emissions were to determine the boiler size. If the record’s daily NO_x emissions were greater

than the average daily NO_x emissions in the default boiler capacity file, it was assumed that the record's boiler capacity was greater than 250 MMBtu/hr. If the record's daily NO_x emissions were less than the average daily NO_x emissions in the default boiler capacity file, it was assumed that the record's boiler capacity was less than 250 MMBtu/hr.

4. If the record had no match in the default boiler capacity file, it was assumed that the record's boiler capacity was less than 250 MMBtu/hr.

Records for which the boiler capacity was estimated to be greater than 250 MMBtu/hr were categorized as large sources. 1995 point-level emissions were checked for each records for which the boiler capacity was estimated to be less than 250 MMBtu/hr. If the 1995 point-level emissions were more than 1 ton/day, the record was categorized as a medium source. Otherwise the record was categorized as a small source.

The large points were modeled with a 70 percent control efficiency applied to their 2007 uncontrolled emissions. The medium points were modeled with RACT-level controls. The RACT-level controls applied were based on national/SCC defaults. The default RACT-level controls used for medium sources are listed in Table III-2. The small points were modeled with the same level of controls they had in the 2007 Base Case. No additional VOC or CO controls were applied in the 2007 Budget Case.

It should be noted that the large and medium source controls were applied to all large and medium sources even if they were less stringent than the 2007 Base Case controls. This resulted in an increase in emissions from the 2007 Base Case to the 2007 Budget Case for some sources. A detailed list of large and medium non-EGU sources including emission, growth and control information is provided in Appendix D.

D. NON-EGU EMISSION SUMMARY

Table III-3 is a State-level summary of the daily non-EGU data. It contains daily emissions for the 1995 base year, the 2007 Base Case, and the 2007 Budget Case. Table III-4 is a comparison of the State-level seasonal emissions to the Base Case and Budget components that were calculated for the November 7, 1997 NPR.

Table III-1
Default Boiler Capacity Data From the NET

6-Digit SCC	Mean Boiler Capacity	Median Boiler Capacity	Boiler Capacity Closest to 250	Daily NOx (tpd) of Boiler with Capacity Closest to 250
102001	75.97	55	264	2.6597
102002	236.65	150	250	0.7282
102003	150.44	58	87	0.4796
102004	393.35	73	250	0.3292
102005	299.63	80	250	0.1365
102006	251.96	86	250	0.2127
102007	268.49	198	250	0.1313
102008	515.30	420	241	1.0534
102009	348.64	132	250	0.2103
102010	123.57	45	224	0.0848
102011	193.00	193	193	0.1606
102012	252.00	180	246	0.4668
102013	194.81	172	250	0.0351
102014	287.62	297	267	0.1636
103001	49.45	43	137	0.2052
103002	90.28	74	248	1.1403
103003	85.00	93	101	0.1194
103004	113.01	59	245	0.0417
103005	89.05	71	249	0.0468
103006	152.38	97	249	0.0468
103007	211.00	197	197	0.7150
103009	65.18	66	166	0.0132
103010	138.00	138	138	0.0179
103012	240.33	75	200	0.5335
103013	93.45	59	250	0.5194
105001	68.22	58	200	0.0035
105002	106.77	108	115	0.0108
202001	228.87	62	276	1.2046
202002	294.62	9	271	0.5596
202005	62.00	62	62	0.1882
202009	70.00	70	70	0.3557
203001	75.00	35	256	8.0303
203002	29.47	8	197	0.7150
204001	567.14	390	210	0.1043
204004	6.00	6	6	0.0223
301001	288.00	288	288	0.6520
301003	760.62	782	445	1.0585
301005	30.50	31	43	0.0143
301006	100.00	100	134	0.1488
301009	31.00	31	31	0.0335

Table III-1
Default Boiler Capacity Data From the NET

6-Digit SCC	Mean Boiler Capacity	Median Boiler Capacity	Boiler Capacity Closest to 250	Daily NOx (tpd) of Boiler with Capacity Closest to 250
301018	42.00	50	70	0.1422
301021	68.00	68	68	0.0902
301023	149.00	168	168	0.0031
301024	310.00	310	310	2.5889
301026	62.00	40	247	0.3385
301030	45.80	29	75	0.0668
301032	17.33	10	60	0.0005
301033	4.00	4	4	0.0030
301035	65.50	52	130	0.9466
301050	1.50	2	2	0.6707
301125	399.50	56	105	0.2021
301140	86.00	86	86	0.1106
301250	189.33	178	230	0.5717
301800	170.00	170	170	1.1550
301888	103.00	103	156	1.1209
301900	9.36	13	16	0.0166
301999	1027.50	40	74	0.5594
302002	5.00	5	5	0.1122
302004	36.00	36	36	0.0633
302007	17.75	17	35	0.1559
302009	95.20	66	260	0.0059
302010	123.00	123	123	0.6380
302999	17.50	18	30	0.0030
303000	4.50	5	6	0.0019
303003	338.27	160	260	0.6746
303008	355.60	227	227	0.6253
303009	244.23	105	263	0.5550
303014	37.74	21	310	0.1934
303999	10.00	10	10	0.0195
304001	11.00	11	11	0.0092
304003	51.33	33	89	0.0127
304004	20.50	21	24	0.0023
304007	24.25	25	36	0.0013
304008	41.00	41	41	0.0624
304020	82.25	93	93	0.1393
304999	28.00	28	52	0.0110
305001	9.20	6	26	0.1109
305002	37.87	21	190	0.0488
305003	17.13	15	29	0.0204
305005	7.00	7	7	0.0033

Table III-1
Default Boiler Capacity Data From the NET

6-Digit SCC	Mean Boiler Capacity	Median Boiler Capacity	Boiler Capacity Closest to 250	Daily NOx (tpd) of Boiler with Capacity Closest to 250
305006	196.75	230	250	0.4356
305007	724.00	724	248	4.2005
305008	42.00	42	42	0.3154
305009	30.00	30	30	0.0129
305010	106.30	100	221	0.1372
305014	55.53	49	150	3.0135
305015	18.11	10	58	0.0506
305016	100.13	103	172	0.4122
305019	76.33	70	89	1.3739
305020	4.00	4	4	0.0283
305021	19.00	19	19	0.0124
305040	110.00	110	110	0.1642
305999	43.00	43	43	0.1661
306001	127.20	63	250	0.2181
306002	243.83	235	238	0.2882
306003	172.00	232	249	0.3476
306011	5.00	5	5	0.0231
306012	126.00	126	126	0.0888
306099	12.50	13	15	0.0303
306888	41.00	41	41	0.4362
306999	21.17	21	31	0.0814
307001	403.92	338	248	0.1822
307002	340.00	340	52	0.0193
307007	44.67	32	160	0.1408
307008	40.00	40	40	0.4065
307013	58.50	59	112	0.0478
307020	24.00	24	37	0.0039
307900	77.33	61	110	0.1716
307999	30.00	25	40	0.1038
308999	46.00	46	46	0.0050
309999	143.17	178	269	0.0564
310002	16.99	6	289	0.1779
310004	39.56	29	118	0.0616
313999	26.00	36	36	0.0013
314999	26.00	36	36	0.0013
390001	5.00	5	5	0.0418
390002	121.50	101	248	4.2005
390004	174.36	71	250	0.3908
390005	32.16	28	141	0.0014
390006	152.17	36	250	0.3908

Table III-1
Default Boiler Capacity Data From the NET

6-Digit SCC	Mean Boiler Capacity	Median Boiler Capacity	Boiler Capacity Closest to 250	Daily NOx (tpd) of Boiler with Capacity Closest to 250
390007	310.48	80	231	0.1690
390008	4.00	4	4	0.0125
390009	88.60	28	357	0.3891
390010	9.57	11	15	0.0032
390013	14.25	8	39	0.0682
399999	30.00	30	30	0.0475
401002	56.00	56	56	0.0224
402001	30.60	5	133	0.0285
402006	2.00	2	2	0.0032
402008	7.13	8	12	0.0035
402009	69.50	70	133	0.0285
402010	6.67	5	12	0.0035
402013	56.00	56	56	0.1172
402017	3.17	5	5	0.0036
402025	46.00	46	46	0.0050
403001	10.00	10	10	0.0099
403011	1.00	1	1	0.0047
404001	20.00	20	20	0.0035
405001	3.33	4	5	0.0017
405005	3.00	3	3	0.0022
406001	56.50	57	70	0.3557
490999	21.00	21	21	0.0348
501001	3345.82	37	375	1.3650
502001	17943.33	245	245	0.0485
502005	1.00	1	1	0.0085
503001	1347.94	10	140	0.3322
503005	276.25	361	361	0.3686

Table III-2
Default NOx RACT Control Assumptions

SCC	NOx RACT Control Group	Default NOx RACT Control Efficiency
10200101	Industrial Boiler - PC	50
10200104	Industrial Boiler - Stoker - Overfeed	55
10200201	Industrial Boiler - PC - Wet	50
10200202	Industrial Boiler - PC - Dry	50
10200203	Industrial Boiler - Cyclone	53
10200204	Industrial Boiler - Stoker - Spreader	55
10200205	Industrial Boiler - Stoker - Overfeed	55
10200206	Industrial Boiler - Stoker	55
10200210	Industrial Boiler - Stoker - Overfeed	55
10200212	Industrial Boiler - PC - Dry	50
10200213	Industrial Boiler - PC - Wet	50
10200217	Industrial Boiler - PC	50
10200219	Cogeneration - Coal	50
10200222	Industrial Boiler - PC - Dry	50
10200223	Industrial Boiler - Cyclone	53
10200224	Industrial Boiler - Stoker - Spreader	55
10200225	Industrial Boiler - Stoker - Overfeed	55
10200229	Cogeneration - Coal	50
10200301	Industrial Boiler - PC	50
10200306	Industrial Boiler - Stoker - Spreader	55
10200401	Industrial Boiler - Residual Oil	50
10200402	Industrial Boiler - Residual Oil	50
10200403	Industrial Boiler - Residual Oil	50
10200404	Industrial Boiler - Residual Oil	50
10200405	Cogeneration - Oil Turbines	68
10200501	Industrial Boiler - Distillate Oil	50
10200502	Industrial Boiler - Distillate Oil	50
10200503	Industrial Boiler - Distillate Oil	50
10200504	Industrial Boiler - Distillate Oil	50
10200505	Cogeneration - Oil Turbines	68
10200601	Industrial Boiler - Natural Gas	50
10200602	Industrial Boiler - Natural Gas	50
10200603	Industrial Boiler - Natural Gas	50
10200604	Cogeneration - Natural Gas Turbines	84
10200699	Industrial Boiler - Natural Gas	50
10200701	Industrial Boiler - Natural Gas	50
10200704	Industrial Boiler - Natural Gas	50
10200707	Industrial Boiler - Natural Gas	50
10200710	Cogeneration - Natural Gas Turbines	84
10200799	Industrial Boiler - Natural Gas	50
10200802	Industrial Boiler - PC	50
10200804	Cogeneration - Coal	50

Table III-2
Default NOx RACT Control Assumptions

SCC	NOx RACT Control Group	Default NOx RACT Control Efficiency
10201001	Industrial Boiler - Natural Gas	50
10201002	Industrial Boiler - Natural Gas	50
10201402	Cogeneration - Coal	50
10300101	Industrial Boiler - PC	50
10300102	Industrial Boiler - Stoker - Overfeed	55
10300103	Industrial Boiler - PC	50
10300205	Industrial Boiler - PC - Wet	50
10300206	Industrial Boiler - PC - Dry	50
10300207	Industrial Boiler - Stoker - Overfeed	55
10300208	Industrial Boiler - Stoker	55
10300209	Industrial Boiler - Stoker - Spreader	55
10300211	Industrial Boiler - Stoker - Overfeed	55
10300217	Industrial Boiler - PC	50
10300221	Industrial Boiler - PC - Wet	50
10300222	Industrial Boiler - PC - Dry	50
10300224	Industrial Boiler - Stoker - Spreader	55
10300225	Industrial Boiler - Stoker - Overfeed	55
10300309	Industrial Boiler - Stoker - Spreader	55
10300401	Industrial Boiler - Residual Oil	50
10300402	Industrial Boiler - Residual Oil	50
10300404	Industrial Boiler - Residual Oil	50
10300501	Industrial Boiler - Distillate Oil	50
10300502	Industrial Boiler - Distillate Oil	50
10300503	Industrial Boiler - Distillate Oil	50
10300504	Industrial Boiler - Distillate Oil	50
10300601	Industrial Boiler - Natural Gas	50
10300602	Industrial Boiler - Natural Gas	50
10300603	Industrial Boiler - Natural Gas	50
10300701	Industrial Boiler - Natural Gas	50
10300799	Industrial Boiler - Natural Gas	50
10301001	Industrial Boiler - Natural Gas	50
10301002	Industrial Boiler - Natural Gas	50
10500205	Process Heaters - Distillate Oil	74
10500206	Process Heaters - Natural Gas	75
10500210	Process Heaters - Other	74
20100101	Gas Turbines - Oil	68
20100102	IC Engines - Oil - Reciprocating	25
20100201	Gas Turbines - Natural Gas	84
20100202	IC Engines - Natural Gas - Reciprocating	30
20100702	Industrial Boiler - Other	50
20100801	Industrial Boiler - Other	50
20100802	Industrial Boiler - Other	50

Table III-2
Default NOx RACT Control Assumptions

SCC	NOx RACT Control Group	Default NOx RACT Control Efficiency
20100901	Industrial Boiler - Other	50
20200101	Gas Turbines - Oil	68
20200102	IC Engines - Oil - Reciprocating	25
20200103	Cogeneration - Oil Turbines	68
20200104	Cogeneration - Oil Turbines	68
20200201	Gas Turbines - Natural Gas	84
20200202	IC Engines - Natural Gas - Reciprocating	30
20200203	Cogeneration - Natural Gas Turbines	84
20200204	Industrial Cogeneration - Nat. Gas	50
20200301	Industrial Boiler - Other	50
20200401	Industrial Boiler - Other	50
20200402	Industrial Boiler - Other	50
20200403	Cogeneration - Oil Turbines	68
20200501	IC Engines - Oil - Reciprocating	25
20200901	Industrial Boiler - Other	50
20200902	Industrial Boiler - Other	50
20201001	IC Engines - Natural Gas - Reciprocating	30
20201002	IC Engines - Natural Gas - Reciprocating	30
20300101	IC Engines - Oil - Reciprocating	25
20300102	Gas Turbines - Oil	68
20300201	IC Engines - Natural Gas - Reciprocating	30
20300202	Gas Turbines - Natural Gas	84
20300203	Cogeneration - Natural Gas Turbines	84
20300204	Cogeneration - Natural Gas Turbines	84
20300301	Industrial Boiler - Other	50
20301001	IC Engines - Natural Gas - Reciprocating	30
20400301	Gas Turbines - Natural Gas	84
20400302	Gas Turbines - Oil	68
20400401	IC Engines - Oil - Reciprocating	25
20400402	IC Engines - Oil - Reciprocating	25
30100101	Adipic Acid Manufacturing Plant	81
30101301	Nitric Acid Manufacturing Plant	95
30101302	Nitric Acid Manufacturing Plant	95
30190003	Process Heaters - Natural Gas	75
30190004	Process Heaters - Natural Gas	75
30390001	Process Heaters - Distillate Oil	74
30390003	Process Heaters - Natural Gas	75
30390004	Process Heaters - Other	74
30490001	Process Heaters - Distillate Oil	74
30490003	Process Heaters - Natural Gas	75
30490004	Process Heaters - Other	74
30590001	Process Heaters - Distillate Oil	74

Table III-2
Default NOx RACT Control Assumptions

SCC	NOx RACT Control Group	Default NOx RACT Control Efficiency
30590002	Process Heaters - Residual Oil	73
30590003	Process Heaters - Natural Gas	75
30600101	Process Heaters - Distillate Oil	74
30600102	Process Heaters - Natural Gas	75
30600103	Process Heaters - Distillate Oil	74
30600104	Process Heaters - Natural Gas	75
30600105	Process Heaters - Natural Gas	75
30600106	Process Heaters - Natural Gas	75
30600107	Process Heaters - Natural Gas	75
30600111	Process Heaters - Residual Oil	73
30600199	Process Heaters - Other	74
30790001	Process Heaters - Distillate Oil	74
30790002	Process Heaters - Residual Oil	73
30790003	Process Heaters - Natural Gas	75
30890003	Process Heaters - Natural Gas	75
30990001	Process Heaters - Distillate Oil	74
30990002	Process Heaters - Residual Oil	73
30990003	Process Heaters - Natural Gas	75
31000401	Process Heaters - Distillate Oil	74
31000403	Process Heaters - Residual Oil	73
31000404	Process Heaters - Natural Gas	75
31000405	Process Heaters - Natural Gas	75
31390003	Process Heaters - Natural Gas	75
39990001	Process Heaters - Distillate Oil	74
39990002	Process Heaters - Residual Oil	73
39990003	Process Heaters - Natural Gas	75
39990004	Process Heaters - Natural Gas	75
40201001	Process Heaters - Natural Gas	75
40201002	Process Heaters - Distillate Oil	74
40201003	Process Heaters - Residual Oil	73
40201004	Process Heaters - Natural Gas	75

TABLE III-3
STATE-LEVEL SUMMARY OF DAILY NON-EGU EMISSIONS
(tons/day)

State	1995 Base Year	2007 Base Case	2007 Budget
AL	246.6	315.0	159.6
CT	37.0	38.4	25.1
DC	28.3	34.9	21.1
DE	2.6	2.0	1.9
GA	185.4	227.4	161.6
IL	521.8	444.3	262.9
IN	280.7	345.3	189.7
KY	103.2	125.9	79.8
MA	90.5	89.2	49.0
MD	76.1	75.0	49.4
MI	353.1	403.0	212.9
MO	77.1	84.8	55.8
NC	143.3	145.3	101.4
NJ	133.8	145.5	117.4
NY	186.4	227.7	127.7
OH	307.8	361.6	210.2
PA	531.2	562.6	318.6
RI	2.2	2.3	2.3
SC	169.3	235.5	127.2
TN	371.9	462.1	215.7
VA	146.3	168.7	74.8
WI	284.8	285.3	138.6
WV	111.8	142.7	78.3
Total	4,391.2	4,924.5	2,781.0

Table III-4
Changes to Proposed Base Case and Budget Components for Non-Electricity Generating Units (tons NO_x/season)

	Proposed Base	Revised Base	Percent Increase	Proposed Budget	Revised Budget	Percent Decrease
Alabama	47,182	48,187	2%	25,131	24,416	3%
Connecticut	4,732	5,254	11%	4,475	3,103	31%
Delaware	5,205	5,276	1%	3,206	2,271	29%
District of Columbia	312	311	0%	312	259	17%
Georgia	34,012	33,939	0%	20,472	14,305	30%
Illinois	63,642	65,351	3%	39,855	40,719	-2%
Indiana	51,432	51,839	1%	35,603	29,187	18%
Kentucky	18,817	19,019	1%	12,258	11,996	2%
Maryland	6,729	10,710	59%	4,825	5,852	-21%
Massachusetts	10,683	9,978	-7%	7,590	6,207	18%
Michigan	57,190	61,656	8%	35,317	35,957	-2%
Missouri	12,248	12,320	1%	8,174	9,012	-10%
New Jersey	32,663	22,228	-32%	26,741	12,786	52%
New York	19,889	20,853	5%	16,930	14,644	14%
North Carolina	32,107	34,412	7%	21,113	19,267	9%
Ohio	50,946	53,329	5%	32,799	30,923	6%
Pennsylvania	64,224	74,839	17%	59,622	41,824	30%
Rhode Island	328	327	0%	328	327	0%
South Carolina	34,791	34,994	1%	20,097	18,671	7%
Tennessee	65,051	67,774	4%	32,138	34,308	-7%
Virginia	23,333	25,509	9%	15,529	10,919	30%
West Virginia	41,510	42,733	3%	31,377	21,066	33%
Wisconsin	21,209	21,263	0%	12,269	11,401	7%
Total	698,233	722,101	3%	466,158	399,416	14%

CHAPTER IV
STATEWIDE NO_X BUDGETS

Chapters II and III primarily focused on the development of daily emissions data for modeling. However, the budgets established by the Ozone Transport SIP Call are seasonal. This Chapter describes how seasonal budgets were calculated from the daily data.

For EGU sources, seasonal data were developed along with the daily data as described in Chapter II. For non-EGU point sources, area sources, nonroad sources and mobile sources, seasonal emissions were calculated using a typical summer weekday level, typical summer Saturday level, and a typical summer Sunday level. Typical summer day emissions were multiplied by 109 (the number of weekdays in the season), and typical Saturday and Sunday emissions were each multiplied by 22 (the number of Saturdays and Sundays in the season), and these were summed to get the seasonal total. Tables IV-1 through IV-7 show the Thursday (typical weekday), Saturday, Sunday, and seasonal emissions for the 2007 CAA Base Case and the proposed budget components for all sectors except EGU. Only the Base Case is presented for area sources because the NO_x emissions from these sources do not change between the Base Case and the Budget.

The Statewide Base Case emissions and Budgets were calculated by summing the individual Base Case emissions and Budget components. Table IV-8 shows the Statewide Base Case and Budget emissions and the percent reduction between the Base Case and the Budget.

Table IV-1
Daily and Seasonal Non-EGU Point Source Emissions for 2007 CAA Base

State	Thursday (tons/day)	Saturday (tons/day)	Sunday (tons/day)	Seasonal (tons/season)
Alabama	314.95	314.95	314.95	48,187
Connecticut	37.62	27.14	25.31	5,254
Delaware	34.82	33.68	33.61	5,276
District of Columbia	2.03	2.03	2.03	311
Georgia	224.98	217.57	210.43	33,939
Illinois	442.08	396	384.18	65,351
Indiana	344.53	328.09	321.24	51,839
Kentucky	125.9	122.56	118.17	19,019
Maryland	94.67	11.06	6.7	10,710
Massachusetts	72.86	47.44	45.11	9,978
Michigan	402.98	402.98	402.98	61,656
Missouri	81.31	79.2	77.94	12,320
New Jersey	145.28	145.28	145.28	22,228
New York	138.02	136.77	127.25	20,853
North Carolina	227.44	219.96	217.37	34,412
Ohio	361.08	319.55	315.52	53,329
Pennsylvania	558.46	376.14	258.73	74,839
Rhode Island	2.34	1.77	1.5	327
South Carolina	235.36	216.54	208	34,994
Tennessee	461.38	404.23	390.47	67,774
Virginia	168.41	163.02	162.09	25,509
West Virginia	283.37	272.46	265.97	42,733
Wisconsin	141.67	132.82	131.78	21,263
Total	4901.54	4371.24	4166.61	722,101

Table IV-2
Daily and Seasonal Non-EGU Point Source Emissions for Proposed Budgets

State	Thursday (tons/day)	Saturday (tons/day)	Sunday (tons/day)	Seasonal (Tons/season)
Alabama	159.58	159.58	159.58	24,416
Connecticut	22.25	16.26	14.53	3,103
Delaware	15.18	14.04	13.97	2,271
District of Columbia	1.69	1.69	1.69	259
Georgia	96.16	90.14	83.65	14,305
Illinois	278.58	240.59	230.04	40,719
Indiana	195.89	180.2	175.92	29,187
Kentucky	79.77	76.44	73.61	11,996
Maryland	51.86	6.41	2.65	5,852
Massachusetts	43.88	33.26	31.46	6,207
Michigan	235.01	235.01	235.01	35,957
Missouri	60.26	56.16	54.91	9,012
New Jersey	83.57	83.57	83.57	12,786
New York	96.55	96.34	90.92	14,644
North Carolina	127.56	123.01	120.74	19,267
Ohio	207.7	190.28	186.25	30,923
Pennsylvania	314.54	201.48	141.21	41,824
Rhode Island	2.34	1.77	1.5	327
South Carolina	127.09	112.39	106.6	18,671
Tennessee	240.31	190.22	178.6	34,308
Virginia	73.05	67.65	66.73	10,919
West Virginia	141.03	130.7	128.12	21,066
Wisconsin	77.21	68.36	67.32	11,401
Total	2,731	2,376	2,249	399,416

Table IV-3
Daily and Seasonal Area Source Emissions for 2007 CAA Base and Budget

State	Thursday (tons/day)	Saturday (tons/day)	Sunday (tons/day)	Seasonal (tons/season)
Alabama	188.01	134.18	81.07	25,229
Connecticut	31.51	27.97	24.43	4,587
Delaware	7.52	5.77	4.01	1,035
District of Columbia	5.42	4.08	2.75	741
Georgia	86.35	66.47	46.66	11,901
Illinois	51.12	42.76	34.4	7,270
Indiana	190	136.56	83.19	25,545
Kentucky	290.25	205.29	120.33	38,801
Maryland	59.23	45	30.76	8,123
Massachusetts	73.76	58.78	43.81	10,297
Michigan	207.08	149.6	102.87	28,126
Missouri	48.15	36.87	25.75	6,626
New Jersey	83.42	62.58	41.75	11,388
New York	113.77	86.17	58.58	15,585
North Carolina	62.81	56.49	50.2	9,193
Ohio	143.03	106.3	68.97	19,446
Pennsylvania	116.61	105.42	94.23	17,103
Rhode Island	2.93	2.51	2.08	420
South Carolina	61.99	45.85	29.75	8,420
Tennessee	87.15	66.49	46.77	11,991
Virginia	188.77	130.1	82.87	25,261
West Virginia	35.76	27.09	18.51	4,901
Wisconsin	75.9	56.93	37.96	10,361
Total	2210.54	1659.26	1131.7	302,350

Table IV-4
Daily and Seasonal Highway Vehicle Emissions for 2007 CAA Base

State	Thursday (07-Jul-88) (tons/day)	Saturday (09-Jul-88) (tons/day)	Sunday (10-Jul-88) (tons/day)	Seasonal (tons/season)
Alabama	416.8	383.27	333.73	61,205
Connecticut	159.47	146.83	128.81	23,446
Delaware	60.3	55.37	48.9	8,867
District of Columbia	20.96	19.25	16.96	3,081
Georgia	599.03	559.68	488.88	88,363
Illinois	622.86	577.8	502.39	91,656
Indiana	491.79	454.17	395.34	72,294
Kentucky	338.91	311.77	272.23	49,789
Maryland	271.66	249.69	219.84	39,941
Massachusetts	240.22	220.88	193.86	35,308
Michigan	622.31	573.69	499.81	91,449
Missouri	420.19	387.72	338.5	61,778
New Jersey	381.86	342.28	301.35	55,783
New York	777.35	714.8	626.24	114,234
North Carolina	551.56	505.43	441.62	80,955
Ohio	710.83	654.3	570.3	104,422
Pennsylvania	556.86	510.13	449.31	81,805
Rhode Island	51.46	47.43	41.52	7,566
South Carolina	365.3	333.38	291.53	53,566
Tennessee	496.75	454.93	397.84	72,907
Virginia	603.89	556.12	487.88	88,792
West Virginia	158.49	145.23	127.11	23,267
Wisconsin	315.35	291.18	255.02	46,390
Total	9234.2	8495.33	7428.97	1,356,864

Table IV-5
Daily and Seasonal Highway Vehicle Proposed Budget Components

State	Weekday (tons/day)	Saturday (tons/day)	Sunday (tons/day)	Seasonal (Tons/season)
Alabama	386.24	352.02	307.13	56,601
Connecticut	118.71	108.25	94.17	17,392
Delaware	57.67	52.39	45.94	8,449
District of Columbia	15.46	14.08	12.33	2,267
Georgia	529.59	483.50	422.61	77,660
Illinois	529.99	484.35	421.19	77,690
Indiana	454.61	416.19	362.53	66,684
Kentucky	315.42	288.39	251.48	46,258
Maryland	195.28	177.74	155.67	28,620
Massachusetts	157.66	144.76	124.84	23,116
Michigan	555.53	507.94	442.08	81,453
Missouri	375.51	343.64	298.43	55,056
New Jersey	268.82	244.12	213.84	39,376
New York	642.00	585.36	509.66	94,068
North Carolina	498.25	454.44	397.71	73,056
Ohio	631.24	577.06	502.21	92,549
Pennsylvania	499.34	454.88	397.32	73,176
Rhode Island	38.89	35.69	30.79	5,701
South Carolina	337.58	307.76	269.83	49,503
Tennessee	461.03	423.72	367.60	67,662
Virginia	544.69	496.87	433.88	79,848
West Virginia	147.62	134.76	117.53	21,641
Wisconsin	284.20	259.18	225.99	41,651
Total	8,045.33	7,347.09	6,404.76	1,179,477

Table IV-6
Daily and Seasonal Nonroad Source Emissions for 2007 CAA Base

State	Thursday (tons/day)	Saturday (tons/day)	Sunday (tons/day)	Seasonal (tons/season)
Alabama	173.69	76.23	51.49	21,742
Connecticut	88.51	49.23	43.09	11,679
Delaware	32.81	25.44	23.96	4,663
District of Columbia	21.57	28.84	28.35	3,609
Georgia	220.12	84.83	58.72	27,151
Illinois	507.12	282.77	210.21	66,122
Indiana	236.76	128.54	84.27	30,489
Kentucky	195.77	107.03	74.24	25,327
Maryland	168.42	86.45	66.22	21,717
Massachusetts	165.96	115.21	101.84	22,865
Michigan	221.63	123.31	97.01	29,005
Missouri	176.03	89.13	65.18	22,582
New Jersey	187.69	115.45	97.83	25,150
New York	278.14	143.35	111.95	35,934
North Carolina	187.45	63.67	47.02	22,867
Ohio	351.08	207.84	153.37	46,214
Pennsylvania	266.25	124.95	88.04	33,707
Rhode Island	19.92	8.29	7.16	2,511
South Carolina	124.95	49.72	33.28	15,446
Tennessee	430.49	200.74	153.19	54,710
Virginia	223.08	127.54	92.65	29,160
West Virginia	79.68	54.72	48.94	10,966
Wisconsin	149.64	77.29	54.4	19,208
Total	4506.76	2370.57	1792.41	582,824

Table IV-7
Daily and Seasonal Nonroad Source Proposed Budget Components

State	Weekday (tons/day)	Saturday (tons/day)	Sunday (tons/day)	Seasonal (tons/season)
Alabama	147.68	71.05	48.49	18,727
Connecticut	70.15	46.48	41.48	9,581
Delaware	29.31	24.87	23.63	4,262
District of Columbia	21.33	28.81	28.33	3,582
Georgia	181.44	78.47	55.04	22,714
Illinois	426.53	256.58	195.12	56,429
Indiana	208.19	121.00	79.88	27,112
Kentucky	172.21	100.43	70.45	22,530
Maryland	136.99	79.87	62.42	18,062
Massachusetts	134.77	110.62	99.16	19,305
Michigan	181.09	113.51	91.31	24,245
Missouri	146.48	81.65	60.88	19,102
New Jersey	158.23	109.23	94.22	21,723
New York	227.21	132.85	105.87	30,018
North Carolina	152.13	60.24	45.02	18,898
Ohio	315.45	199.31	148.32	42,032
Pennsylvania	227.00	117.70	83.81	29,176
Rhode Island	16.05	7.85	6.89	2,074
South Carolina	102.63	44.47	30.26	12,831
Tennessee	364.63	187.28	145.44	47,065
Virginia	190.70	119.67	88.11	25,357
West Virginia	71.74	53.22	48.07	10,048
Wisconsin	116.38	64.64	47.14	15,145
Total	3,798.32	2,209.80	1,699.34	500,018

Table IV-8
Summary of Revised 2007 Base and Budget Seasonal NO_x Emissions

	EGU		Non-EGU Point		Highway		Nonroad		Area	Total		
State	**Base**	**Budget**	**Base**	**Budget**	**Base**	**Budget**	**Base**	**Budget**	**Base**	**Base**	**Budget**	**% Red.**
Alabama	85,201	30,644	48,187	24,416	61,205	56,601	21,742	18,727	25,229	241,564	155,617	36%
Connecticut	7,048	5,245	5,254	3,103	23,446	17,392	11,679	9,581	4,587	52,014	39,909	23%
Delaware	10,727	4,994	5,276	2,271	8,867	8,449	4,663	4,262	1,035	30,568	21,010	31%
District of Columbia	236	152	311	259	3,081	2,267	3,609	3,582	741	7,978	7,000	12%
Georgia	84,890	32,433	33,939	14,305	88,363	77,660	27,151	22,714	11,901	246,243	159,013	35%
Illinois	119,756	36,570	65,351	40,719	91,656	77,690	66,122	56,429	7,270	350,154	218,679	38%
Indiana	159,917	51,818	51,839	29,187	72,294	66,684	30,489	27,112	25,545	340,084	200,345	41%
Kentucky	130,919	38,775	19,019	11,996	49,789	46,258	25,327	22,530	38,801	263,855	158,360	40%
Maryland	37,575	12,971	10,710	5,852	39,941	28,620	21,717	18,062	8,123	118,065	73,628	38%
Massachusetts	24,998	14,651	9,978	6,207	35,308	23,116	22,865	19,305	10,297	103,445	73,575	29%
Michigan	73,585	29,458	61,656	35,957	91,449	81,453	29,005	24,245	28,126	283,821	199,238	30%
Missouri	81,799	26,450	12,320	9,012	61,778	55,056	22,582	19,102	6,626	185,104	116,246	37%
New Jersey	17,484	8,191	22,228	12,786	55,783	39,376	25,150	21,723	11,388	132,032	93,464	29%
New York	43,705	31,222	20,853	14,644	114,234	94,068	35,934	30,018	15,585	230,310	185,537	19%
North Carolina	86,872	32,691	34,412	19,267	80,955	73,056	22,867	18,898	9,193	234,300	153,106	35%
Ohio	167,601	51,493	53,329	30,923	104,422	92,549	46,214	42,032	19,446	391,012	236,443	40%
Pennsylvania	120,979	45,971	74,839	41,824	81,805	73,176	33,707	29,176	17,103	328,433	207,250	37%
Rhode Island	1,351	1,609	327	327	7,566	5,701	2,511	2,074	420	12,175	10,132	17%
South Carolina	57,146	19,842	34,994	18,671	53,566	49,503	15,446	12,831	8,420	169,572	109,267	36%
Tennessee	83,844	26,225	67,774	34,308	72,907	67,662	54,710	47,065	11,991	291,225	187,250	36%
Virginia	51,113	20,990	25,509	10,919	88,792	79,848	29,160	25,357	25,261	219,835	162,375	26%
West Virginia	76,374	24,045	42,733	21,066	23,267	21,641	10,966	10,048	4,901	158,240	81,701	48%
Wisconsin	45,538	17,345	21,263	11,401	46,390	41,651	19,208	15,145	10,361	142,759	95,902	33%
Total	1,568,655	563,784	722,101	399,416	1,356,862	1,179,478	582,822	500,018	302,350	4,532,790	2,945,046	35%

References

DOE, 1995a: U.S. Department of Energy, Energy Information Administration, "Steam-Electric Plant Operation and Design Report," Form EIA-767, 1995.

DOE, 1995b: U.S. Department of Energy, Energy Information Administration, "Annual Electric Generator Report," Form EIA-860, 1995.

DOE, 1995c: U.S. Department of Energy, Energy Information Administration, "Annual Nonutility Power Producers Report," Form EIA-867, 1995.

EPA, 1997b: U.S. Environmental Protection Agency, Data files received from EPA Acid Rain Division, Washington DC, December 1997.

EPA, 1997c: U.S. Environmental Protection Agency, "National Air Pollutant Emission Trends, 1900-1996," EPA-454/R-97-011, Research Triangle Park, NC, December, 1997.

Pechan, 1997a: E.H. Pechan & Associates, Inc., "Ozone Transport Assessment Group (OTAG) Emissins Inventory Development Report - Volume I: 1990 Base Year Development," (revised draft) prepared for U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, NC, February, 1997.

Pechan, 1997b: E.H. Pechan & Associates, Inc., "Ozone Transport Assessment Group (OTAG) Emissins Inventory Development Report - Volume III: Projections and Controls," (draft) prepared for U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, NC, June, 1997.

Pechan, 1997c: E.H. Pechan & Associates, Inc., "The Acid Rain Data Base for 1996 (ARDB96) Technical Support Document," (draft) prepared for U.S. Environmental Protection Agency, Office of Atmospheric Programs, September 1997.

APPENDIX A
LIST OF DAILY EGU INVENTORY

APPENDIX B
LIST OF SEASONAL EGU INVENTORY

APPENDIX C
LIST OF SOURCES MOVED FROM OTAG UTILITY TO NON-EGU DATA

APPENDIX D
LIST OF LARGE AND MEDIUM NON-EGU SOURCES